Financial Statements: Electric

evapco

BALANCE SHEETS

ASSETS	June 30, 2011	June 30, 2010
	(in thousands)	
UTILITY PLANT:		
Production	$ 426,064	$ 274,030
Transmission	29,152	28,484
Distribution	477,373	456,691
General	39,557	39,825
	972,146	799,030
Less accumulated depreciation	(352,343)	(331,216)
	619,803	467,814
Land	7,645	7,612
Intangible	9,821	-
Construction in progress	39,787	126,578
Nuclear fuel, at amortized cost	4,878	4,773
Total utility plant (Note 3)	681,934	606,777
RESTRICTED ASSETS:		
Cash and cash equivalents (Note 2)	22,237	21,215
Cash and investments at fiscal agent (Note 2)	270,273	179,777
Total restricted non-current assets	292,510	200,992
OTHER NON-CURRENT ASSETS:		
Advances to City	5,558	650
Deferred pension costs (Note 1)	12,736	13,027
Deferred bond issuance costs	7,128	6,847
Deferred debits (Note 4)	10,016	18,279
Total other non-current assets	35,438	38,803
Total non-current assets	1,009,882	846,572
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	168,905	170,292
Accounts receivable, less allowance for doubtful accounts 2011 $1,161; 2010 $2,003	35,524	31,509
Advances to City	4,195	-
Accrued interest receivable	1,381	913
Prepaid expenses	12,660	10,748
Nuclear materials inventory	1,905	1,825
Total unrestricted current assets	224,570	215,287
Restricted assets:		
Public Benefit Programs - Cash and cash equivalents (Note 2)	3,882	7,168
Public Benefit Programs receivable	697	619
Total restricted current assets	4,579	7,787
Total current assets	229,149	223,074
Total assets	$ 1,239,031	$ 1,069,646

See accompanying notes to the financial statements

BALANCE SHEETS

EQUITY AND LIABILITIES		June 30, 2011		June 30, 2010
		(in thousands)		
EQUITY:				
Invested in capital assets, net of related debt	$	225,055	$	222,016
Restricted for:				
Debt service (Note 5)		22,237		21,215
Public Benefit Programs		3,771		7,389
Unrestricted		199,057		189,431
Total equity		450,120		440,051
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (NOTE 4)		594,613		479,174
OTHER NON-CURRENT LIABILITIES:				
Pension obligation (Notes 1 and 4)		12,381		12,705
Nuclear decommissioning liability (Notes 1 and 4)		67,969		63,552
Postemployment benefits payable (Notes 1 and 4)		2,775		2,004
Derivative instruments (Note 4)		17,216		22,073
Loan Payable - Corona (Note 4)		44,141		-
Capital leases payable (Notes 1 and 4)		1,303		1,699
Total non-current liabilities		145,785		102,033
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:				
Accrued interest payable		6,382		4,085
Public Benefit Programs payable		808		398
Current portion of long-term obligations (Note 4)		20,940		22,705
Total current liabilities payable from restricted assets		28,130		27,188
CURRENT LIABILITIES:				
Accounts payable and other accruals		15,922		18,312
Customer deposits		3,033		2,888
Loan Payable - Corona (Note 4)		1,428		-
Total current liabilities		20,383		21,200
Total liabilities		788,911		629,595
COMMITMENTS AND CONTINGENCIES (Notes 8 and 9)		-		-
Total equity and liabilities	$	1,239,031	$	1,069,646

See accompanying notes to the financial statements

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN EQUITY

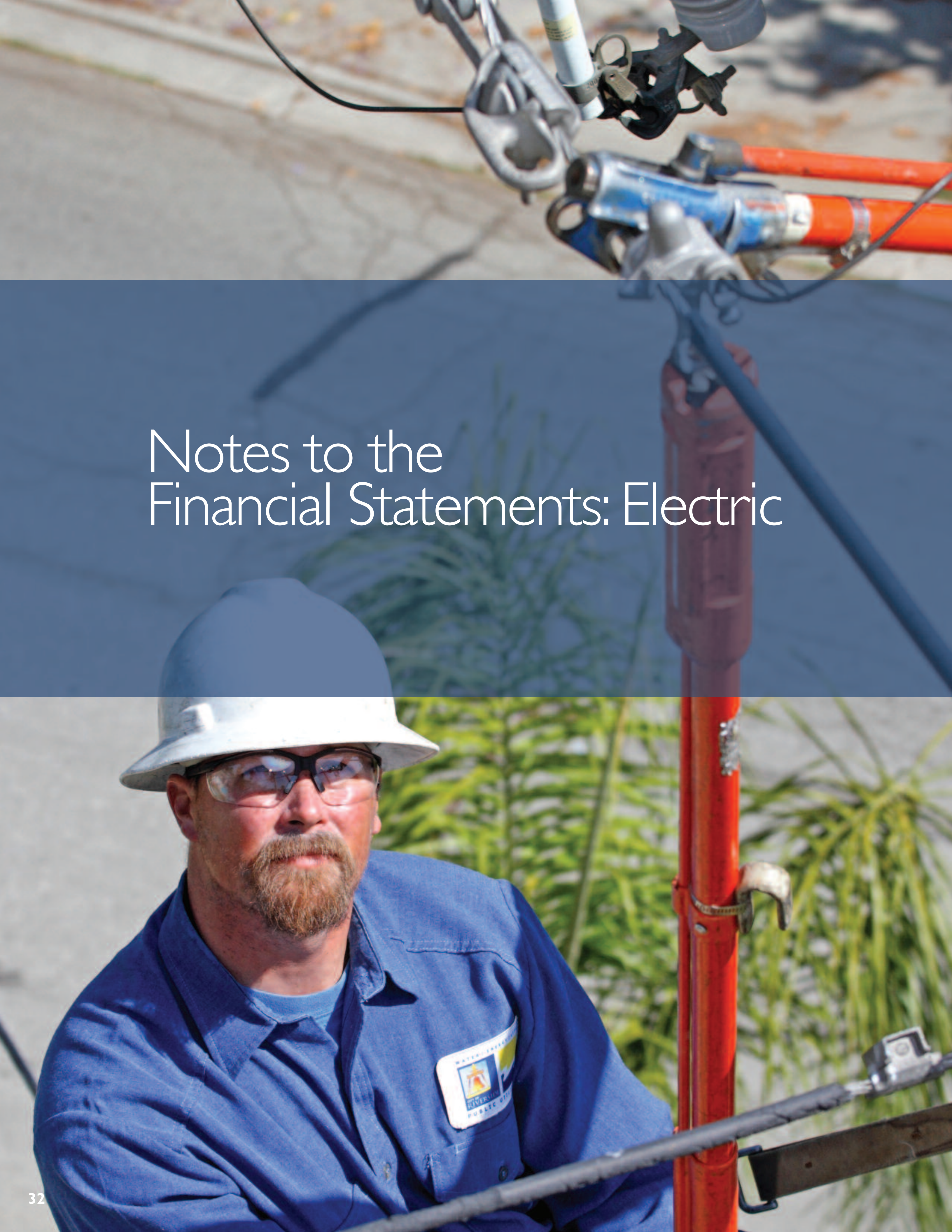
	For the Fiscal Years Ended June 30, 2011	2010
	(in thousands)	
OPERATING REVENUES:		
Residential sales	$ 107,792	$ 107,301
Commercial sales	64,039	65,091
Industrial sales	102,067	97,458
Other sales	5,529	5,639
Wholesale sales	124	1,466
Transmission revenue	22,091	21,100
Other operating revenue	4,015	3,806
Public Benefit Programs	8,046	8,049
Total operating revenues before (reserve)/recovery	313,703	309,910
Reserve for uncollectible, net of bad debt recovery	(1,021)	(1,283)
Total operating revenues, net of (reserve)/recovery	312,682	308,627
OPERATING EXPENSES:		
Production and purchased power	128,962	127,162
Transmission	40,434	33,030
Distribution	44,931	41,637
Public Benefit Programs	11,664	8,784
Depreciation	27,690	25,375
Total operating expenses	253,681	235,988
Operating income	59,001	72,639
NON-OPERATING REVENUES (EXPENSES):		
Investment income	10,368	16,009
Interest expense and fiscal charges	(21,220)	(19,589)
Gain on retirement of utility plant	5,931	543
Other	2,117	2,362
Total non-operating revenues (expenses)	(2,804)	(675)
Income before capital contributions and transfers	56,197	71,964
Capital contributions	4,056	3,477
Transfers out - contributions to the City's general fund	(33,070)	(33,656)
Total capital contributions and transfers out	(29,014)	(30,179)
Income before special item	27,183	41,785
SPECIAL ITEM:		
Intra-entity property acquisition	(17,114)	-
Increase in equity	10,069	41,785
EQUITY, BEGINNING OF YEAR	440,051	398,266
EQUITY, END OF YEAR	$ 450,120	$ 440,051

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2011 (in thousands)	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 308,733	$ 315,305
Cash paid to suppliers and employees	(223,049)	(207,844)
Other receipts	2,117	2,362
Net cash provided by operating activities	87,801	109,823
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(33,070)	(33,656)
Principal paid on pension obligation bonds	(324)	(274)
Intra-entity property acquisition	(17,114)	-
Advances to City	(3,545)	5,269
Net cash used by non-capital financing activities	(54,053)	(28,661)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(50,331)	(60,218)
Purchase of nuclear fuel	(1,554)	(1,854)
Proceeds from the sale of utility plant	495	787
Deposit to escrow account for advanced bond refunding	-	(36,800)
Proceeds from revenue bonds, including premium	140,857	37,124
Principal paid on long-term obligations	(23,086)	(21,674)
Interest paid on long-term obligations	(24,985)	(23,404)
Capital contributions	2,925	1,610
Bond issuance costs	(1,124)	(348)
Net cash provided (used) by capital and related financing activities	43,197	(104,777)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds (purchase) of investment securities	273	(5,822)
Income from investments	9,900	15,841
Net cash provided by investing activities	10,173	10,019
Net increase (decrease) in cash and cash equivalents	87,118	(13,596)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR (**including $110,095 and $159,100 at June 30, 2010 and June 30, 2009, respectively, reported in restricted accounts)**	280,387	293,983
CASH AND CASH EQUIVALENTS, END OF YEAR (**including $198,600 and $110,095 at June 30, 2011 and June 30, 2010, respectively, reported in restricted accounts)**	$ 367,505	$ 280,387
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 59,001	$ 72,639
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation	27,690	25,375
Amortization of deferred charges-pension costs	291	232
Amortization of nuclear fuel/purchased power	1,449	2,717
Decrease in allowance for uncollectible accounts	(843)	(2)
(Increase) decrease in accounts receivable	(3,251)	6,571
Increase in prepaid expenses	(1,912)	(4,524)
Increase in nuclear materials inventory	(80)	(75)
Decrease in accounts payable and other accruals	(2,404)	(343)
Increase in postemployment benefits payable	771	775
Increase (decrease) in Public Benefit Programs	410	(492)
Increase in customer deposits	145	108
Increase in decommissioning liability	4,417	4,480
Other receipts	2,117	2,362
Net cash provided by operating activities	$ 87,801	$ 109,823
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	1,131	1,867
(Decrease) increase in fair value of investments	(470)	1,788
Principal balance of revenue bonds refunded	56,450	-

See accompanying notes to the financial statements



Notes to the Financial Statements: Electric

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Electric Utility exists under, and by virtue of, the City of Riverside (the City) Charter enacted in 1883. The Electric Utility is responsible for the generation, transmission and distribution of electric power for sale in the City. The accompanying financial statements present only the financial position and the results of operations of the Electric Utility (the Utility), which is an enterprise fund of the City, and are not intended to present fairly the financial position and results of operations of the City in conformity with generally accepted accounting principles. However, certain disclosures are for the City as a whole, since such information is generally not available for the Fund on a separate fund basis. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

BASIS OF ACCOUNTING

The Electric Utility uses the accrual basis of accounting as required for enterprise funds with accounting principles generally accepted in the United States of America as applicable to governments. The accounting records of the Utility are also substantially in conformity with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC). The Utility is not subject to the regulations of the FERC. The Utility is not required to and does not elect to implement the pronouncements of the Financial Accounting Standards Board issued after November 1989.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during a reporting period. Actual results could differ from those estimates.

REVENUE RECOGNITION

The Electric Utility customers are billed monthly. Unbilled electric service charges including the Public Benefit Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable, totaled $13,339 at June 30, 2011, and $13,271 at June 30, 2010.

An allowance for doubtful accounts is maintained for utility and miscellaneous accounts receivable. The balance in this account is adjusted at fiscal year-end to approximate the amount anticipated to be uncollectible.

UTILITY PLANT AND DEPRECIATION

The Electric Utility defines capital assets as assets with an initial, individual cost of more than five thousand dollars and an estimated useful life in excess of one year. Utility plant assets are valued at historical cost or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; interest during construction; allocated indirect charges such as engineering, supervision, construction and transportation equipment; retirement plan contributions and other fringe benefits. Contributed plant assets are valued at estimated fair value on the date contributed. The cost of relatively minor replacements is included in maintenance expense. Intangible assets that cost more than one hundred thousand dollars with useful lives of at least three years are capitalized and are recorded at cost.

Depreciation is provided over the estimated useful lives of the related assets using the straight-line method. The estimated useful lives are as follows:

Production plant	11-30 years
Transmission and distribution plant	20-50 years
General plant and equipment	3-50 years

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

NUCLEAR FUEL

The Electric Utility amortizes and charges to expense, the cost of nuclear fuel, on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. In accordance with the Nuclear Waste Disposal Act of 1982, the Utility is charged one dollar per megawatt-hour of energy generated by the Utility's share of San Onofre Nuclear Generating Station's (SONGS) Units 2 and 3 to provide for estimated future storage and disposal of spent nuclear fuel. The Utility pays this fee to its operating agent, Southern California Edison Co (SCE), on a quarterly basis (see Note 7).

RESTRICTED ASSETS

Proceeds of revenue bonds yet to be used for capital projects, as well as certain resources set aside for debt service, are classified as restricted assets on the Balance Sheets because their use is limited by applicable bond covenants. Funds set aside for the nuclear decommissioning reserve are also classified as restricted assets because their use is legally restricted to a specific purpose.

In January 1998, the Electric Utility began collecting a surcharge for Public Benefit Programs on customer utility bills. This surcharge is mandated by state legislation included in Assembly Bill 1890 and is restricted to various socially beneficial programs and services. The programs and services include cost effective demand-side management services to promote energy efficiency and conservation and related education and information; ongoing support and new investments in renewable resource technologies; energy research and development; and programs and services for low-income electric customers. The activity associated with the surcharge for Public Benefit Programs is reflected in the accompanying financial statements on the Balance Sheets, Statements of Revenues, Expenses and Changes in Equity, and Statements of Cash Flows.

CASH AND INVESTMENTS

In accordance with the Electric Utility policy, the Utility's cash and investments, except for cash and investments with fiscal agents, are invested in a pool managed by the Treasurer of the City. The Utility does not own specific, identifiable investments of the pool. The pooled interest earned is allocated monthly based on the month end cash balances.

The Utility values its cash and investments in accordance with the provisions of the Governmental Accounting Standards Board (GASB) Statement No. 31, *Accounting and Financial Reporting for Certain Investments and External Investment Pools* (GASB 31), which requires governmental entities, including governmental external investment pools, to report certain investments at fair value in the Statement of Net Assets/Balance Sheets and recognize the corresponding change in the fair value of investments in the year in which the change occurred. Fair value is determined using quoted market prices.

Cash accounts of all funds are pooled for investment purposes to enhance safety and liquidity, while maximizing interest earnings.

City-wide information concerning cash and investments for the year ended June 30, 2011, including authorized investments, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments may be found in the notes to the City's "Comprehensive Annual Financial Report."

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the Electric Utility and are pledged as collateral for payment of principal and interest on outstanding bonds, funds set aside to decommission the Utility's proportionate share of units 2 and 3 at SONGS, or for use on construction of capital assets.

INTERNALLY RESTRICTED CASH RESERVES

Effective July 1, 2003, the City Council approved a Regulatory Risk Reserve Account of $4,000, an Energy Risk Management Reserve Account of $11,000, and an Operating Reserve Account of $14,000, all of which are considered internally restricted assets. The balance as of June 30, 2011 and 2010 respectively are as follows: Regulatory Risk Reserve $15,000 and $15,000, Energy Risk Management Reserve $30,000 and $30,000 and Operating Reserve $95,031 and $80,531, for a combined total of $140,031 and $125,531 and are reflected in cash and cash equivalents in the accompanying Balance Sheets.

ADVANCES

Advances have been recorded as a result of agreements between the Electric Utility and the City. The balance as of June 30, 2011 and 2010 was $9,753 and $650, respectively.

DERIVATIVES

On July 1, 2009, the Electric Utility adopted GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). This Statement requires the Utility to report its derivative instruments at fair value. Changes in fair value for effective hedges are to be reported as deferrals on the Balance Sheets. Changes in fair value of derivative instruments not meeting the criteria for an effective hedge, or that are associated with investments are to be reported in the investment section of the Statements of Revenues, Expenses and Changes in Equity.

The Utility has determined that its interest rate swaps associated with variable rate obligations are derivative instruments under GASB 53. The swaps are comprised of an "At-the-Market Swap" derivative instrument and an "Off-Market Swap" deferral balance as described below.

The Utility's evaluation of the "At-the-Market Swap" has concluded that it is an effective hedge under the synthetic instrument method. As a result, upon implementation of GASB 53 beginning July 1, 2009, the negative fair value of the "At-the-Market Swap" has been recorded and deferred on the Balance Sheets. The Balance Sheets for June 30, 2009 have been restated to reflect the retroactive application of GASB 53. Disclosure requirements are presented in Note 4 under Interest Rate Swaps on Revenue Bonds.

The "Off-Market Swap" deferral balance was a result of the refunding of the variable rate obligations that occurred in 2008 and 2011. Under GASB 53, hedge accounting ceased to be applied on the interest rate swaps associated with the obligations upon the occurrence of the refunding. Since new variable rate bonds were issued in the refunding, the deferral balance has been treated as a deferred loss and is included in the net carrying amount of the new bonds as reported on the Balance Sheets under long-term obligations.

Various transactions permitted in the Utility's Power Resources Risk Management Policies may be considered derivatives, including energy and/or gas transactions for swaps, options, forward arrangements and congestion revenue rights. GASB 53 allows an exception for the Balance Sheet deferral hedges that meet the normal purchases and normal sales exception. It is the Utility's policy to apply the normal purchases and normal sales exception as appropriate.

The Utility determined for fiscal year ended June 30, 2010 that congestion revenue rights (CRRs) associated with power transmission within the California Independent System Operator (CAISO) were derivative instruments under GASB 53 for the reporting year and did not meet the normal purchases and normal sales exception. However, in December 2010, GASB reversed its position on CRRs and allowed the application of normal purchases and normal sales exception in which the fair values are not required to be deferred on the Balance Sheets. Thus, the Utility has reversed its recording of derivative instruments assets and deferred credits related to the CRRs that were previously reported on its Balance Sheets. The Balance Sheets for June 30, 2010 have been restated to reflect the reversal of GASB 53 position as it relates to the CRRs.

BOND PREMIUMS, ISSUANCE COSTS, GAINS AND LOSSES ON REFUNDING

Bond premiums, issuance costs, and gains and losses on refunding (including gains and losses related to interest rate swap transactions) are deferred and amortized over the life of the bonds using the effective interest method. Bonds payable are reported net of the applicable bond premiums and gain or loss on refunding, whereas issuance costs are recorded as other assets.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

NUCLEAR DECOMMISSIONING LIABILITY

Federal regulations require the Electric Utility to provide for the future decommissioning of its ownership share of the nuclear units at San Onofre. The Utility has established a trust account to accumulate resources for the decommissioning of the nuclear power plant and restoration of the beachfront at San Onofre. Based on the most recent site specific cost estimate as of February 2009 prepared by ABZ Incorporated, the Utility plans to set aside approximately $1,600 per year to fund this obligation. The funding will occur over the useful life of the generating plant or until the account is fully funded.

Increases to the trusts are from amounts set aside and investment earnings. The investment earnings are included in investment income in the Utility's financial statements. These amounts, as well as amounts set aside, are contributed to the trusts and reflected as decommissioning expense, which are considered part of power supply costs. The total amounts held in the trust accounts are classified as restricted assets and other non-current liability in the accompanying Balance Sheets. To date, the Utility has set aside $67,969 in cash investments with the trustee as the Utility's estimated share of the decommissioning cost of San Onofre. The plant site easement at San Onofre terminates May 2024. The plant must be decommissioned and the site restored by the time the easement terminates.

CAPITAL LEASES

The Electric Utility has entered into eight capital lease agreements as a lessee for financing eight compressed natural gas heavy duty service trucks. These leases have seven year terms with monthly payments with interest rates ranging from 3.24% to 5.87%. The total gross value of the leases is $2,728 with depreciation over the seven year terms of the leases using the straight-line method.

For fiscal year ended June 30, 2011 and 2010, the total liability was $1,692 and $2,073, respectively, with the current portion included in accounts payable and other accruals. The minimum annual lease payments for the life of the leases are $442 annually through fiscal year ended June 30, 2014, $429 in the fiscal year ended June 30, 2015, and $65 in the fiscal year ended June 30, 2016. Total outstanding lease payments are $1,819, with $1,692 representing the present value of the net minimum lease payments and $127 representing interest.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills. The Electric Utility's portion of these deposits as of June 30, 2011 and 2010 was $3,033 and $2,888, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2011 and 2010. The Electric Utility including the Public Benefit Programs, treats compensated absences due to employees as an expense and a current liability. The amount accrued for compensated absences was $4,275 at June 30, 2011, and $4,092 at June 30, 2010, and is included in accounts payable and other accruals in the accompanying Balance Sheets.

Employees receive 10 to 25 vacation days per year based upon length of service. A maximum of two years vacation accrual may be accumulated and unused vacation is paid in cash upon separation.

Employees primarily receive one day of sick leave for each month of employment with unlimited accumulation. Upon retirement or death, certain employees or their estates receive a percentage of unused sick-leave paid in a lump sum based on longevity.

INSURANCE PROGRAMS

The Electric Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The Utility pays an amount to the City based on actuarial estimates of the amounts needed to fund prior and current year claims and incidents that have been incurred but not reported. The City maintains property insurance on most City property holdings, including the Utility Plant with a limit of $1 billion.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risk for the year ended June 30, 2011, may be found in the notes to the City's "Comprehensive Annual Financial Report."

Although the ultimate amount of losses incurred through June 30, 2011 is dependent upon future developments, management believes that amounts paid to the City are sufficient to cover such losses. Premiums paid to the City by the Electric Utility including the Public Benefit Programs, were $713 and $884 for the years ended June 30, 2011 and 2010, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Utility in future years.

EMPLOYEE RETIREMENT PLAN

The City contributes to the California Public Employees Retirement System (PERS), an agent multiple-employer public employee retirement system that acts as a common investment and administrative agency for participating public entities within the State of California.

All permanent full-time and selected part-time employees are eligible for participation in PERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. Employees may retire at age 55 and receive 2.7 percent of their highest annual salary for each year of service completed. PERS also provides death and disability benefits. These benefit provisions and all other requirements are established by state statute and City ordinance.

Employee contributions are 8.0 percent of their annual covered salary. The Electric Utility including the Public Benefit Programs is required to contribute the remaining amounts necessary to fund the benefits for its employees using the actuarial basis recommended by the PERS actuaries and actuarial consultants and adopted by the PERS Board of Administration. The employer portion of the PERS funding as of June 30, 2011 and 2010 was 14.51 percent and 14.22 percent, respectively, of annual covered payroll. The Utility pays both the employee and employer contributions. The total Electric Utility's contribution to PERS as of June 30, 2011 and 2010 was $7,063 and $6,885 respectively.

City-wide information concerning elements of the unfunded actuarial accrued liabilities, contributions to PERS for the year ended June 30, 2011 and recent trend information may be found in the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2011.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PENSION OBLIGATION BONDS

In 2005, the City issued Pension Obligations Bonds in the amount of $60,000, of which the Electric Utility's, including the Public Benefit Programs, share is $13,690. The deferred charge relating to the net pension asset will be amortized over 19 years in accordance with the method used by PERS for calculating actuarial gains and losses. The Bond proceeds were deposited with PERS to fund the unfunded actuarial accrued liability for non-safety employees. The balance in deferred pension costs as of June 30, 2011 and 2010 was $12,736 and $13,027, respectively as reflected in the accompanying Balance Sheets as deferred pension costs and a corresponding long-term obligation. For more discussion relating to the City's issue, see the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2011.

OTHER POSTEMPLOYMENT BENEFITS

The City contributes to two single-employer defined benefit healthcare plans: Stipend Plan (SP) and the Implied Subsidy Plan (ISP). The plans provide other postemployment health care benefits (OPEB) for eligible retirees and beneficiaries.

The Stipend Plan is available to eligible retirees and beneficiaries pursuant to their collective bargaining agreements. The Electric Utility currently contributes to two bargaining units through the International Brotherhood of Electrical Workers General Trust (IBEW) and Service Employee's International Union General Trust (SEIUG). Benefit provisions for the Stipend Plan for eligible retirees and beneficiaries are established and amended through the various memoranda of understanding (MOU). The MOU's are agreements established between the City and the respective employee associations. The City does not issue separate stand-alone financial reports for the plans, instead financial information for the trust funds can be obtained by contacting the individual association.

The Utility also provides benefits to retirees in the form of an implicit rate subsidy (Implied Subsidy). Under an implied rate subsidy, retirees and current employees are insured together as a group, thus creating a lower rate for retirees than if they were insured separately. Although the retirees are solely responsible for the cost of their health insurance benefits through this plan, the retirees are receiving the benefit of a lower rate.

The contribution requirements of the Utility for the Stipend Plan are established and may be amended through the MOU between the City and the unions. The Utility's contribution is financed on a "pay-as-you-go-basis" and the current contribution is unfunded. The contribution requirements of the Utility's Implied Subsidy Plan are established by the City Council. The Utility is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries.

The Utility's annual OPEB cost (expense) for each plan is calculated based on annual required contribution of the employer (ARC), an amount actuarially determined in accordance with the parameters of GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions* (GASB 45). The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year and amortize any unfunded actuarial liabilities (or funding excess) (UAAL) over a period not to exceed thirty years. The Electric Utility's OPEB liability including the Public Benefit Programs as of June 30, 2011 and 2010 was $2,834 and $2,053, respectively.

City-wide information concerning the description of the plans, funding policy and annual OPEB cost, funding status and funding progress, and actuarial methods and assumptions for the year ended June 30, 2011 can be found in the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2011.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

ARBITRAGE LIABILITY

The Tax Reform Act of 1986 (the Act) requires the Electric Utility to calculate and remit rebatable arbitrage earnings to the Internal Revenue Service. Certain debt and interest earnings on the proceeds of the Utility are subject to the requirements of the Act which contain yield restrictions on investment of proceeds from tax-exempt financing in higher yielding taxable securities. The balance in the arbitrage liability as of June 30, 2011 and June 30, 2010 was $102 and $27 respectively, and is included in accounts payable and other accruals in the accompanying Balance Sheets.

EQUITY

The Electric Utility's equity consists of its net assets (assets less liabilities) which are classified into the following three components:

Invested in capital assets, net of related debt – this component consists of capital assets (net of accumulated depreciation) and unamortized debt expenses reduced by the outstanding balances of any bonds or other borrowings that are attributable to the acquisition, construction, or improvement of those assets.

Restricted – this component consists of net assets on which constraints are placed as to their use. Constraints include those imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

Unrestricted – this component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt."

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter, the Electric Utility may transfer up to 11.5 percent of its prior year's gross operating revenues to the City's general fund. In fiscal years ended June 30, 2011 and 2010, the Electric Utility transferred approximately 11.5 percent of gross operating revenues less wholesale sales and Public Benefit Programs revenues, or $33,070 and $33,656, respectively.

CASH AND CASH EQUIVALENTS

For the Statements of Cash Flows, cash and cash equivalents include all unrestricted and restricted highly liquid investments with original purchase maturities of three months or less, and all bond construction proceeds available for capital projects. Pooled cash and investments in the City's Treasury represent monies in a cash management pool. Such accounts are similar in nature to demand deposits, and are classified as cash equivalents for the purpose of presentation in the Statements of Cash Flows.

BUDGET AND BUDGETARY ACCOUNTING

The Electric Utility presents, and the City Council adopts, an annual budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council adopts the Utility's budget in June each year via resolution.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform with the current year's presentation.

PRIOR YEAR DATA

Selected information regarding the prior year has been included in the accompanying financial statements. This information has been included for comparison purposes only and does not represent a complete presentation in accordance with generally accepted accounting principles. Accordingly, such information should be read in conjunction with the Electric Utility's prior year financial statements, from which this selected financial data was derived.

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2011 and 2010, consist of the following (in thousands):

	June 30, 2011	June 30, 2010
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 195,024	$ 198,675
Cash and investments at fiscal agent	270,273	179,777
Total cash and investments	$ 465,297	$ 378,452

The amounts above are reflected in the accompanying financial statements as:

	June 30, 2011	June 30, 2010
Unrestricted cash and cash equivalents	$ 168,905	$ 170,292
Restricted cash and cash equivalents	26,119	28,383
Restricted cash and investments at fiscal agent	270,273	179,777
Total cash and investments	$ 465,297	$ 378,452

Cash and investments distribution by maturities as of year end are as follows:

		Remaining Maturity (In Months)			
Investment Type	Total	12 Months or less	13 to 24 Months	25 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 3,963	$ 3,963	$ -	$ -	$ -
State investment pool	29,188	29,188	-	-	-
Federal agency securities	46,276	2,160	6,511	24,861	12,744
Investment contracts [1]	166,543	-	-	151,828	14,715
Corp medium term notes	24,303	1,230	3,154	11,674	8,245
City Treasurer's investment pool [2]		-	-	-	-
Money market funds	14,560	14,560	-	-	-
Federal agency securities	93,198	8,071	34,564	50,563	-
Corp medium term notes	25,208	4,911	7,603	12,694	-
State investment pool	59,839	59,839	-	-	-
Neg Certificate of Deposit	2,219	-	120	2,099	-
Total	$ 465,297	$ 123,922	$ 51,952	$ 253,719	$ 35,704

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of year end for each investment type:

Investment Type	Total	Rating as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 3,963	$ 3,922	$ -	$ -	$ 41
State investment pool	29,188	-	-	-	29,188
Federal agency securities	46,276	46,276	-	-	-
Investment contracts	166,543	-	-	-	166,543
Corp medium term notes	24,303	-	18,573	5,730	-
City Treasurer's investment pool [2]		-	-	-	-
Money market funds	14,560	9,460	5,100	-	-
Federal agency securities	93,198	93,198	-	-	-
Corp medium term notes	25,208	25,208	-	-	-
State investment pool	59,839	-	-	-	59,839
Neg Certificate of Deposit	2,219	-	-	-	2,219
Total	$ 465,297	$ 178,064	$ 23,673	$ 5,730	$ 257,830

1 Amounts related to bond construction proceeds are invested in specific maturities but are available for construction of capital assets as funding is needed.

2 Additional information on investment types and credit risk may be found in the City's "Comprehensive Annual Financial Report."

NOTE 3. UTILITY PLANT

The following is a summary of changes in utility plant during the fiscal years ended June 30, 2011 and 2010 (in thousands):

	Balance, As of 6/30/2009	Additions	Retirements/ Transfers	Balance, As of 6/30/2010	Additions	Retirements/ Transfers	Balance, As of 6/30/2011
Production	$ 266,470	$ 7,560	$ -	$ 274,030	$ 152,668	$ (634)	$ 426,064
Transmission	27,544	940	-	28,484	668	-	29,152
Distribution	426,515	30,798	(622)	456,691	22,738	(2,056)	477,373
General	38,752	2,052	(979)	39,825	4,333	(4,601)	39,557
Depreciable utility plant	759,281	41,350	(1,601)	799,030	180,407	(7,291)	972,146
Less accumulated depreciation:							
Production	(137,419)	(10,306)	-	(147,725)	(11,701)	106	(159,320)
Transmission	(11,541)	(630)	-	(12,171)	(650)	-	(12,821)
Distribution	(142,957)	(12,043)	622	(154,378)	(12,833)	2,056	(165,155)
General	(15,282)	(2,396)	736	(16,942)	(2,506)	4,401	(15,047)
Accumulated depreciation	(307,199)	(25,375)	1,358	(331,216)	(27,690)	6,563	(352,343)
Net depreciable utility plant	452,082	15,975	(243)	467,814	152,717	(728)	619,803
Land	7,612	-	-	7,612	60	(27)	7,645
Intangibles	-	-	-	-	9,821	-	9,821
Construction in progress	102,234	65,695	(41,351)	126,578	50,813	(137,604)	39,787
Nuclear fuel	3,966	1,924	(1,117)	4,773	1,554	(1,449)	4,878
Nondepreciable utility plant	113,812	67,619	(42,468)	138,963	62,248	(139,080)	62,131
Total utility plant	$ 565,894	$ 83,594	$ (42,711)	$ 606,777	$ 214,965	$ (139,808)	$ 681,934

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2011 and 2010 (in thousands):

	Balance As of 6/30/2009	Additions	Reductions	Balance As of 6/30/2010	Additions	Reductions	Balance As of 6/30/2011	Due Within One Year
Revenue bonds	$ 523,715	$ 36,401	$ (58,237)	$ 501,879	$ 192,722	$ (79,048)	$ 615,553	$ 20,940
Pension obligation	12,979	-	(274)	12,705	-	(324)	12,381	379
Postemployment benefits			-					
payable	1,229	775	-	2,004	771	-	2,775	-
Nuclear decommissioning liability	59,072	4,480	-	63,552	4,417	-	67,969	-
Capital leases	2,433	-	(360)	2,073	-	(381)	1,692	388
Loan Payable Corona	-	-	-	-	45,569	-	45,569	1,428
Total long-term obligations	$ 599,428	$ 41,656	$ (58,871)	$ 582,213	$ 243,479	$ (79,753)	$ 745,939	$ 23,135

LOAN PAYABLE

The Electric Utility entered into the Clearwater Power Plant Purchase and Sale Agreement dated March 3, 2010 with the City of Corona for the acquisition of Clearwater Cogeneration Facility (Clearwater) located in Corona. Clearwater is a combined-cycle, natural gas generating facility with a gross plant output of 29.5 MW. Following a "transition period" during which the Utility engaged in pre-closing activities and due diligence inspection, the transaction closed on September 1, 2010 and the Utility took ownership of the plant. The purchase also included construction of a substation and the 69,000 volt facilities necessary to transfer power from Clearwater Power Plant to the SCE's electrical distribution system to California's high voltage transmission grid. The useful life of Clearwater and the related transmission facilities is anticipated to be at least thirty years. The total purchase price for Clearwater is $45,569, and will be funded through a series of semi-annual payments ranging from $1,158 to $2,664 through 2013, and $182 through $413 from 2014 through 2015. In addition, two payments of $36,406 and $7,367 are due in 2013 and 2015, respectively, and will be funded primarily from bond proceeds.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Long-term debt consists of the following (in thousands):

REVENUE BONDS PAYABLE

		June 30, 2011		June 30, 2010
$47,215 2001 Electric Revenue Bonds: serial bonds due in annual installments from $3,670 to $3,855 through October 1, 2012, interest at 5.0 percent; (partially advance refunded in 2005 and 2009)	$	7,525	$	11,030
$75,405 2003 Electric Refunding/Revenue Bonds: serial bonds due in annual installments from $880 to $8,535 through October 1, 2013, interest from 4.0 percent to 5.0 percent		23,665		31,625
$27,500 2004 Electric Revenue Series A Bonds: serial bonds due in annual installments from $2,645 to $3,695 through October 1, 2014, interest from 5.0 percent to 5.5 percent.		13,125		16,295
$199,115 2008 Electric Refunding/Revenue Bonds:				
A - **$84,515 2008 Series A Bonds** - variable rate bonds due in annual installments from $1,250 to $7,835 from October 1, 2014 through October 1, 2029. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 29, 2011 was 3.1 percent)		84,515		84,515
B - **$57,275 2008 Series B Bonds** - all outstanding bonds were refinanced with the 2011 series A Revenue/Refunding Bonds on April 28, 2011		-		56,725
C - **$57,325 2008 Series C Bonds** - variable rate bonds due in annual installments from $700 to $5,200 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 29, 2011 was 3.2 percent)		56,450		56,750
$209,740 2008 Electric Revenue Series D Bonds: fixed rate bonds due in annual installments from $1,875 to $24,960 from October 1, 2017 through October 1, 2038, interest from 3.6 to 5.0 percent		209,740		209,740
$34,920 2009 Electric Refunding/Revenue Series A Bonds: fixed rate bonds due in annual installments from $450 to $6,105 through October 1, 2018, interest from 3.0 percent to 5.0 percent		27,425		34,920
$140,380 2010 Electric Revenue Bonds:				
A - **$133,290 2010 Electric Revenue Series A Bonds:** fixed rate, federally taxable Build America Bonds due in annual installments from $2,300 to $33,725 from October 1, 2020 through October 1, 2040, interest from 3.9 percent to 4.9 percent		133,290		-
B - **$7,090 2010 Electric Revenue Series B Bonds:** fixed rate bonds due in annual installments from $95 to $2,440, from October 1, 2016 through October 1, 2019, interest from 3.0 percent to 5.0 percent		7,090		-
$56,450 2011 Electric Revenue/Refunding Series A Bonds: variable rate bonds due in annual installments from $725 to $5,175, from October 1, 2011 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 29, 2011 was 3.1 percent)		56,450		-
Total electric revenue bonds payable		619,275		501,600
Unamortized deferred bond refunding costs		(13,813)		(11,142)
Unamortized bond premium		10,091		11,421
Total electric revenue bonds payable, net of deferred bond refunding costs and bond premium		615,553		501,879
Less current portion		(20,940)		(22,705)
Total long-term electric revenue bonds payable	$	594,613	$	479,174

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Annual debt service requirements to maturity, excluding amounts for nuclear decommissioning liability, as of June 30, 2011, are as follows (in thousands):

	2012	2013	2014	2015	2016	2017-2021	2022-2026	2027-2031	2032-2036	2037-2041	Total
Principal	$ 20,940	$ 21,905	$ 20,685	$ 14,480	$ 15,415	$ 68,380	$ 81,705	$ 99,720	$ 122,650	$ 153,395	$ 619,275
Interest	$ 26,531	$ 25,551	$ 24,543	$ 23,745	$ 23,113	$ 108,340	$ 94,398	$ 75,736	$ 51,670	$ 19,753	473,380
Total	$ 47,471	$ 47,456	$ 45,228	$ 38,225	$ 38,528	$ 176,720	$ 176,103	$ 175,456	$ 174,320	$ 173,148	$ 1,092,655

The Electric Utility's bond indentures require the Utility to maintain a minimum debt service coverage ratio, as defined by the bond covenants of 1.10. The Electric Utility's debt service coverage ratio was 2.21 and 2.75 at June 30, 2011 and 2010, respectively. This debt (revenue bonds) is backed by the revenues of the Utility.

PRIOR YEAR DEFEASANCE OF DEBT

In prior years, the Electric Utility defeased certain Revenue Bonds by placing the proceeds of the new bonds in an irrevocable trust to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the Utility's financials statements. At fiscal year ended June 30, 2011, $17,600 of bonds outstanding are considered defeased.

2010 ELECTRIC REVENUE BONDS

On December 16, 2010, the Electric Utility issued $133,290 of Electric Revenue Series A Bonds (federally taxable, Build America Bonds) to finance certain Electric System Improvements as outlined in the 5-year Capital Improvement Program, including system reliability projects such as a 230-69 kV transmission substation and upgrades to the Utility's generation stations. Annual principal payments ranging from $2,300 to $33,725 are due from October 1, 2020 through October 1, 2040, with associated interest rates of 3.91% to 4.94%.

On December 16, 2010, the Utility also issued $7,090 of Electric Revenue Series B Bonds to finance certain Electric System Improvements as outlined in the 5-year Capital Improvement Program. Annual principal payments ranging from $95 to $2,440 are due from October 1, 2016 through October 1, 2019, with associated interest rates of 3.00% to 5.00%.

2011 ELECTRIC REFUNDING/REVENUE BONDS

In April 2008, the Electric Utility refinanced $199,115 of Auction Rate Securities (ARS) with Variable Rate Demand Notes (VRDNs). Due to the 2008 financial market meltdown, the ARS experienced failed auctions. VRDNs in conjunction with the Utility's interest rate hedges (discussed in the Interest Rate Swaps on Revenue Bonds section) have proven to be very effective in lowering the overall debt costs. VRDNs require additional credit enhancements (e.g. insurance or a bank letter of credit) to ensure timely payment to the bondholders. In 2008, the Utility used Letter of Credit (LOC) provided by Bank of America/Merrill Lynch (BAML), at very attractive rates, which required BAML to make debt service payments to bondholders should the Utility fail to make payment. The LOC with BAML expired in April 2011 and due to the number of entities seeking to renew their expiring LOCs combined with the shrinking number of highly-rated banks offering this service, renewing the existing LOC with BAML resulted in higher rates. Therefore, the Utility decided to restructure one of the three 2008 VRDNs in order to mitigate various risk exposures and to provide an overall lower cost of financing by refunding the 2008 VRDNs with the 2011 VRDNs (as described below).

Because one variable rate debt product was exchanged for another, the typical refunding disclosure measuring the difference in aggregate debt service and calculating an economic gain or loss is less relevant, as the future cash flows of each leg of the calculation are uncertain. For this reason, only the terms of the transaction are described.

On April 28, 2011, $56,450 of Electric Refunding/Revenue Series A Bonds were sold with an all-in true interest cost of 3.89% to refund $56,450 of previously outstanding 2008 Electric Refunding/Revenue Series B Bonds. The refunding resulted in a difference between the reacquisition price and the net carrying amount of the old debt of $193. The difference is being charged to operations using the proportional method. Principal payments are due on October 1, 2011 until the maturity date of October 1, 2035 ranging from $725 to $5,175.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS

The Electric Utility has three cash flow hedging derivative instruments, which are pay-fixed swaps. These swaps were determined to be hedge-effective under the synthetic instrument method. The changes in fair value during the reporting period were reported as deferred debits.

A summary of the derivative activity for the year ended June 30, 2011 is as follows:

	Notional Amount	Fair Value as of 6/30/2011	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 84,515	$ (7,028)	$ 1,719
2008 Electric Refunding/Revenue Bonds Series C	$ 57,325	$ (5,108)	$ 1,569
2011 Electric Refunding/Revenue Bonds Series A	$ 56,450	$ (5,080)	$ 1,569

Objective: In order to lower borrowing costs as compared to fixed-rate bonds, the Utility entered into interest rate swap agreements in connection with its $141,840 2008 Electric Revenue Bonds (Series A and C) and $56,450 2011 Electric Revenue Bonds.

Terms: Per the existing swap agreements, the Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68% of the London Interbank Offering Rate ("LIBOR") one month index plus 12 basis points. The swaps have notional amounts equal to the principal amounts stated above. The notional value of the swaps and the principal amounts of the associated debt decline by $1,250 to $7,835 (2008 Series A), $700 to $5,200 (2008 Series C) and $725 to $5,175 (2011 Series A) until the debt is completely retired in fiscal year 2036.

The bonds and the related swap agreements for the 2008 Electric Revenue Series A Bonds mature on October 1, 2029 and the 2008 Electric Revenue Series C and 2011 Electric Revenue Series A Bonds mature on October 1, 2035. As of June 30, 2011, rates were as follows:

		2008 Electric Refunding/Revenue Series A Bonds	2008 Electric Refunding/Revenue Series C Bonds	2011 Electric Refunding/Revenue Series A Bonds
Interest rate swap:	Terms	Rates	Rates	Rates
Fixed payment to counterparty	Fixed	3.11100%	3.20400%	3.20100%
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.58955%)	(0.59206%)	(0.24534%)
Net interest rate swap payments		2.52145%	2.61194%	2.95566%
Variable-rate bond coupon payments		0.58891%	0.58498%	0.14349%
Synthetic interest on bonds		3.11036%	3.19692%	3.09915%

Fair value: As of June 30, 2011, in connection with all swap agreements, the transactions had a total negative fair value of ($17,216). Because the coupons on the Utility's variable-rate bonds adjust to changing interest rates, the bonds do not have a corresponding fair value decrease. The fair value was developed by a pricing service using the zero-coupon method. This method calculates the future net settlement payments required by the swap, assuming that the current forward rates implied by the yield curve correctly anticipate future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for hypothetical zero-coupon bonds due on the date of each future net settlement of the swap.

Credit risk: As of June 30, 2011, the Utility was not exposed to credit risk because the swap had a negative fair value. The swap counterparties, J.P. Morgan Chase & Co and Merrill Lynch were rated A+ and A, respectively by Standard & Poor's. To mitigate the potential for credit risk, the swap agreements require the fair value of the swap to be collateralized by the counterparty with U.S. Government securities if the counterparties' rating decreases to negotiated trigger points. Collateral would be posted with a third-party custodian. At June 30, 2011, there is no requirement for collateral posting for any of the outstanding swaps.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Basis risk: As noted above, the swaps expose the Utility to basis risk should the relationship between LIBOR and the variable interest rate, changing the synthetic rate on the bonds. If a change occurs that results in the rates moving to convergence, the expected cost savings may not be realized.

Termination risk: The derivative contract uses the International Swap Dealers Association Master Agreement, which includes standard termination events, such as failure to pay and bankruptcy. The Schedule to the Master Agreement includes an "additional termination event." That is, a swap may be terminated by the Utility if either counterparty's credit quality falls below "BBB-" as issued by Standard & Poor's. The Utility or the counterparty may terminate a swap if the other party fails to perform under the terms of the contract. If a swap is terminated, the variable-rate bond would no longer carry a synthetic interest rate. Also, if at the time of termination a swap has a negative fair value, the Utility would be liable to the counterparty for a payment equal to the swap's fair value.

Swap payments and associated debt: As of June 30, 2011, the debt service requirements of the variable-rate debt and net swap payments, assuming current interest rates remain the same for their term, are summarized as follows. As rates vary, variable-rate bond interest payments and net swap payments will vary.

	Variable-Rate Bonds			
Fiscal Year Ending June 30,	**Principal**	**Interest**	**Interest Rate Swaps, Net**	**Total**
2012	$ 2,650	$ 899	$ 5,200	$ 8,749
2013	2,750	889	5,124	8,763
2014	2,850	879	5,044	8,773
2015	4,800	858	4,914	10,572
2016	12,275	805	4,583	17,663
2017-2021	40,925	3,413	19,571	63,909
2022-2026	39,850	2,385	14,265	56,500
2027-2031	42,940	1,305	9,079	53,324
2032-2036	48,375	365	2,787	51,527
Total	$ 197,415	$ 11,798	$ 70,567	$ 279,780

NOTE 5. RESTRICTED EQUITY

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of equity. Bond indentures for the Utility's electric revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110% of the monthly accrued interest to be included in the reserve. Certain bond issues are covered by a Surety Bond (2008 Revenue Series D) and certain issues have no debt service reserve requirements (2009 Revenue/Refunding Series A, 2010 Revenue Series A and B and 2011 Refunding Series A bonds).


200 120V 3W TYPE CN1SR 30TA 1.0Kh
CITY OF RIVERSIDE
CA 0.5
FM12S
60Hz
52 438 579
Itron
WATTHOUR METER
USA 9/07
200 120V 3W TYPE CN1SR 30TA 1.0Kh
CITY OF RIVERSIDE
CA 0.5
FM12S
60Hz
*2HF052438538
52 438 538
Itron
WATTHOUR METER
USA 9/07

NOTE 6. JOINTLY-GOVERNED ORGANIZATIONS

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

On November 1, 1980, the City of Riverside joined with the Imperial Irrigation District and the cities of Los Angeles, Anaheim, Vernon, Azusa, Banning, Colton, Burbank, Glendale and Pasadena to create the Southern California Public Power Authority (SCPPA) by a Joint Powers Agreement under the laws of the State of California. As of July 2001, the cities of Cerritos and San Marcos were admitted as members of SCPPA. In August 2003, the Authority rescinded the membership of the City of San Marcos, as the City no longer met the criteria for membership. The primary purpose of SCPPA is to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. SCPPA is governed by a Board of Directors, which consists of one representative from each of the members. During the 2010-11 and 2009-10 fiscal years, the Electric Utility paid approximately $18,725 and $15,151, respectively, to SCPPA under various take-or-pay contracts that are described in greater detail in Note 8. These payments are reflected as a component of production and purchased power or transmission expense in the financial statements.

POWER AGENCY OF CALIFORNIA

On July 1, 1990, the City of Riverside joined with the cities of Azusa, Banning and Colton to create the Power Agency of California (PAC) by a Joint Powers Agreement under the laws of the State of California. The City of Anaheim joined PAC on July 1, 1996. The primary purpose of PAC is to take advantage of synergies and economies of scale as a result of the five cities acting in concert. PAC has the ability to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. PAC is governed by a Board of Directors, which consist of one representative from each of the members. The term of the Joint Powers Agreement is 50 years. Effective June 30, 2001, PAC was placed in an inactive status by the Board of Directors. The Agency can only be reactivated by authorization of the Agency Board.

NOTE 7. JOINTLY-OWNED UTILITY PROJECT

Pursuant to a settlement agreement with SCE, dated August 4, 1972, the Electric Utility was granted the right to acquire a 1.79 percent ownership interest in SONGS Units 2 and 3, equating to 19.2 MW and 19.3 MW respectively, of the available capacity. In the settlement agreement, SCE agreed to provide the necessary transmission service to deliver the output of SONGS to Riverside. SCE and the Utility entered into the SONGS Participation Agreement that sets forth the terms and conditions under which the Utility participates in the ownership and output of SONGS. Other participants in this project include SCE, 75.05 percent; San Diego Gas & Electric Company, 20.00 percent; and the City of Anaheim, 3.16 percent. Maintenance and operation of SONGS remain the responsibility of SCE, as operating agent for the Utility.

During 2006, the FERC, Nuclear Regulatory Commission (NRC) and the California Public Utility Commission (CPUC) approved the transfer of Anaheim's shares to SCE, and as a result, SCE's ownership was increased to 78.21 percent in SONGS Units 2 and 3.

The original operating license for SONGS Units 2 and 3 was set to expire in 2013; however, this was subsequently extended due to a construction recapture provision, and now expires February 16, 2022 and November 15, 2022 for Units 2 and 3 respectively. During fiscal year ended June 30, 2006, the City Council approved participation in SONGS through the extended operations date. It has been reported that SCE is pursuing a license extension from the NRC to continue operations through 2042, although the City Council has not approved its participation in the project through the extended term.

SCE, as operating agent, declared an "operating impairment" due to deterioration of the steam generators (SGs), which would have likely resulted in permanent shutdown of the plant in 2009-2010 timeframe. The estimated cost to replace the SGs is

NOTE 7. JOINTLY-OWNED UTILITY PROJECT (CONTINUED)

$680,000, of which approximately $12,200 would represent the Utility's share. Replacement of the SGs is expected to enable plant operations through at least 2022, and perhaps beyond if NRC approval is obtained. The City Council has approved participation in the replacement of the SGs. The SG replacement for SONGS Unit 2 was completed in April 2010 and the SG replacement for Unit 3 was completed in February 2011.

Due to the Fukushima nuclear power plant crisis in Japan early this year, NRC has instituted a comprehensive review of disaster preparedness of all nuclear power plants currently in operation in the U.S. SONGS has participated and is continuing to participate in this comprehensive disaster preparedness assessment effort. The ultimate outcome of this assessment is currently undetermined.

There are no separate financial statements for the jointly-owned utility plant since each participant's interests in the utility plant and operating expenses are included in their respective financial statements. The Electric Utility's 1.79 percent share of the capitalized construction costs for SONGS totaled $159,907 and $152,586 for fiscal years ended June 30, 2011 and 2010, respectively.

All acquisitions or construction of capital assets are depreciated through 2022, to include the construction recapture extension period. The accumulated depreciation amounted to $133,260 and $126,837 for the fiscal years ended June 30, 2011 and 2010, respectively. The Electric Utility made provisions for future decommissioning costs of $1,581 for both fiscal years plus earnings on the Decommissioning Trust Fund of $2,836 and $2,898 for fiscal years June 30, 2011 and June 30, 2010, respectively (see Note 1). The Utility's portion of current and long-term debt associated with SONGS is included in the accompanying financial statements.

NOTE 8. COMMITMENTS

TAKE-OR-PAY CONTRACTS

The Electric Utility has entered into a power purchase contract with Intermountain Power Agency (IPA) for the delivery of electric power. The Utility's share of IPA power is equal to 7.6 percent, or approximately 137.1 MW, of the net generation output of IPA's 1,800 MW coal-fueled generating station located in central Utah. The contract expires in 2027 and the debt fully matures in 2024.

The contract constitutes an obligation of the Utility to make payments solely from operating revenues. The power purchase contract requires the Utility to pay certain minimum charges that are based on debt service requirements and other fixed costs. Such payments are considered a cost of production.

The Utility is a member of SCPPA, a joint powers agency (see Note 6). SCPPA provides for the financing and construction of electric generating and transmission projects for participation by some or all of its members. To the extent the Utility participates in projects developed by SCPPA, it has entered into Power Purchase or Transmission Service Agreements, entitling the Utility to the power output or transmission service, as applicable, and the Utility will be obligated for its proportionate share of the project costs whether or not such generation output of transmission service is available.

The projects and the Utility's proportionate share of SCPPA's obligations, including final maturities and contract expirations are as follows:

Project	Percent Share	Entitlement	Final Maturity	Contract Expiration
Palo Verde Nuclear Generating Station	5.4 percent	12.3 MW	2017	2030
Southern Transmission System	10.2 percent	244.0 MW	2027	2027
Hoover Dam Uprating	31.9 percent	30.0 MW	2017	2017
Mead-Phoenix Transmission	4.0 percent	18.0 MW	2020	2030
Mead-Adelanto Transmission	13.5 percent	118.0 MW	2020	2030

NOTE 8. COMMITMENTS (CONTINUED)

As part of the take-or-pay commitments with IPA and SCPPA, the Utility has agreed to pay its share of current and long-term obligations. Management intends to pay these obligations from operating revenues received during the year that payment is due. A long–term obligation has not been recorded on the accompanying financial statements for these commitments. Take-or-pay commitments terminate upon the later of contract expiration or final maturity of outstanding bonds for each project.

Interest rates on the outstanding debt associated with the take-or-pay obligations range from variable rates from 0.03 percent to 3.00 percent and fixed rates from 3.50 percent to 6.00 percent. The schedule below details the amount of principal and interest that is due and payable by the Utility as part of the take-or-pay contract for each project in the fiscal year indicated.

	IPA	SCPPA					TOTAL
Debt Service Payment (in thousands) Year Ending June 30,	Intermountain Power Project	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Upgrading	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2012	$ 22,118	$ 659	$ 7,140	$ 706	$ 311	$ 3,026	$ 33,961
2013	20,017	662	11,069	704	310	3,019	35,781
2014	22,712	664	8,482	705	310	3,019	35,892
2015	21,154	668	8,503	703	261	3,005	34,294
2016	23,942	672	8,527	702	267	2,999	37,109
2017-2021	93,356	1,353	37,159	1,399	1,264	14,274	148,804
2022-2026	25,182	-	32,209	-	-	-	57,391
2027-2031	-	-	7,154	-	-	-	7,154
Total	$ 228,481	$ 4,678	$ 120,243	$ 4,919	$ 2,723	$ 29,342	$ 390,386

In addition to debt service, the Utility's entitlements require the payment of fuel costs, operating and maintenance, administrative and general and other miscellaneous costs associated with the generation and transmission facilities discussed above. These costs do not have a similar structured payment schedule as debt service and vary each year. The costs incurred for the year ended June 30, 2011 and 2010, are as follows (in thousands):

FISCAL YEAR	Intermountain Power Project	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Upgrading	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2011	$ 29,530	$ 2,792	$ 2,460	$ 100	$ 43	$ 298	$ 35,223
2010	$ 27,458	$ 2,991	$ 1,779	$ 68	$ 40	$ 265	$ 32,601

These costs are included in production and purchased power or transmission expense on the Statements of Revenues, Expenses and Changes in Equity.

The Utility has become a Participating Transmission Owner (PTO) with the CAISO (see Note 9) and has turned over the operational control of its transmission entitlements including the Southern Transmission System, Mead-Phoenix and Mead-Adelanto Transmission Projects. In return users of the California's high voltage transmission grid are charged for, and the Utility receives reimbursement for, its transmission revenue requirements (TRR), including the costs associated with these three transmission projects.

POWER PURCHASE AGREEMENTS

The Electric Utility has executed two firm power purchase agreements with Bonneville Power Administration (BPA). The first agreement with BPA was for the purchase of firm capacity (23 megawatts in the summer months and 16 megawatts in the winter months) beginning February 1, 1991, for a period of 20 years. This agreement terminated on March 3, 2011. The second BPA agreement is for the purchase of capacity (50 megawatts during the summer months and 13 megawatts during the winter months) beginning April 30, 1996, for 20 years. Effective May 1, 1998, these summer and winter capacity amounts increased to 60 megawatts and 15 megawatts, respectively, for the remainder of the second agreement.

NOTE 8. COMMITMENTS (CONTINUED)

NUCLEAR INSURANCE

The Price-Anderson Act (the Act) requires that all utilities with nuclear generating facilities purchase the maximum private primary nuclear liability insurance available ($375 Million) and participate in the industry's secondary financial protection plan. The secondary financial protection program is the industry's retrospective assessment plan that uses deferred premium charges from every licensed reactor owner if claims and/or costs resulting from a nuclear incident at any licensed reactor in the United States were to exceed the primary nuclear insurance at that plant's site. The Act limits liability from third-party claims to approximately $12.6 billion per incident. Under the industry wide retrospective assessment program provided for under the Act, assessments are limited to $117.5 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $17.5 million per reactor, per year, per event to be indexed for inflation every five years. The next inflation adjustment will occur no later than October 29, 2013. Based on the Electric Utility's interest in Palo Verde and ownership in SONGS, the Utility would be responsible for a maximum assessment of $5,331, limited to payments of $794 per incident, per year. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

RENEWABLE PORTFOLIO STANDARD (RPS)

On June 6, 2003 and July 8, 2003, the Public Utilities Board and the City Council respectively, adopted a RPS to increase procurement of renewable resources to reach a target of 20% of the Utility's energy by 2015. On March 16, 2007, the Public Utilities Board approved a new RPS, increasing the targets to 20% and 25% by 2010 and 2015, respectively. On May 4, 2007, the Public Utilities Board added an additional target of 33% by 2020. The City Council, on December 9, 2008, unanimously approved the revised RPS.

The contracts in the following table were executed as part of compliance with this standard. The Electric Utility also has an agreement with Bonneville Power Administration for the purchase of energy credits that add to the total renewable portfolio. The Utility met its 20% goal by the end of 2010 calendar year, as adopted by the City Council.

Long-term renewable power purchase agreements (in thousands):

Supplier	Type	Maximum Contract	Contract Expiration	Estimated Annual Cost For 2012
Salton Sea Power LLC	Geothermal	46.0 MW	5/31/2020	$ 21,139
Wintec	Wind	8.0 MW	11/10/2021	200
Total		54.0 MW		$ 21,339

All contracts are contingent on energy production from specific related generating facilities. The Utility has no commitment to pay any amounts except for energy produced on a monthly basis from these facilities.

On August 23, 2005, the City Council approved an amendment to the Purchase Power Agreement ("PPA") between Salton Sea and the Utility. The agreement increases the amount of renewable energy available to the Utility from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020, at the same price under the current contract until 2013, with escalation thereafter based on an inflationary type index. Similar to other renewable power purchase agreements, the Utility is only obligated for purchases of energy delivered to the City.

On November 10, 2006, the Utility entered into a second Renewable PPA with Wintec Energy, Ltd for wind generation capacity of up to 8 MW on their proposed Wintec Facility II Wind Turbine Project. The contract term is for 15 years, expiring November 10, 2021. The developer is encountering challenges in finding suitable wind turbines to complete the project and the project is expected to continue to be delayed.

On June 19, 2008, and December 12, 2008, respectively the Utility entered into two separate Renewable Power Purchase Agreements with Shoshone Renaissance, LLC (Renaissance). The contract term for each agreement is 30 years, and provides a combined 96 megawatts of geothermal energy. Like the majority of renewable projects, Renaissance continues to experience

NOTE 8. COMMITMENTS (CONTINUED)

difficulty securing financing due to the meltdown in the financial markets. In November 2010, the Utility entered into the Amended and Restated PPA I and terminated PPA II. The Amended and Restated PPA I reduced the geothermal power deliveries from 64 MW to 46 MW with the new commercial operation date extended to April 1, 2014. Measurable milestone dates and enforceable agreement termination "off-ramps" for the Utility were built into this agreement to allow the Utility the unilateral ability to terminate the Amended and Restated PPA I. On February 15, 2011 Shoshone Renaissance failed the first milestone as established in the Amended and Restated PPA I. The Utility notified Shoshone Renaissance in March 2011 of the Utility's intent to terminate the Amended and Restated PPA I by April 1, 2011 and provided an opportunity to Shoshone Renaissance to cure its failure to reach the first milestone. However, Shoshone Renaissance failed to provide evidence to cure its default by April 1, 2011. Thus, the Utility provided the final termination notice to Shoshone Renaissance and the Amended and Restated PPA I was terminated on April 1, 2011.

CONSTRUCTION COMMITMENTS

As of June 30, 2011, the Electric Utility had major commitments (encumbrances) of approximately $19,290 with respect to unfinished capital projects, of which $17,248 is expected to be funded by bonds and $2,042 funded by other sources.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet summer peaking requirements, the Electric Utility may contract on a monthly or quarterly basis, for the purchase or sale of natural gas, electricity and/or capacity products on a short term horizon. As of June 30, 2011, the Electric Utility has net commitments for fiscal year 2012 and thereafter, of approximately $15,307, with a market value of $14,383.

NOTE 9. LITIGATION

The Electric Utility continues to participate in key FERC dockets impacting the Utility, such as the CAISO's Market Redesign and Technology Upgrade (MRTU).

On January 1, 2003, the Utility became a PTO with the CAISO, entitling the Utility to receive compensation for use of its transmission facilities committed to the CAISO's operational control. The compensation is based on the Utility's TRR as approved by the FERC.

On July 1, 2011, the Utility filed a revised TRR at FERC. In its filing, the Utility updated its projected transmission costs and proposed to reaffirm an automatic adjustment mechanism to reflect its actual costs incurred under existing transmission contracts with Southern California Edison which have become the most volatile component of its TRR.

Numerous parties have filed timely motions to intervene, with some parties protesting various portions of the TRR. The Electric Utility has required an increased TRR of $31,693, an increase of $6,178 to the Utility's existing Base TRR. The Utility expects that this matter will be scheduled for briefing and hearings before FERC. The Utility has again requested that FERC allow the Utility to automatically recover further cost increases imposed by Southern California Edison without filing an application with FERC for a new TRR tariff, and expects that this request will be granted.

During the California Energy Crisis of 2001-2002, the Utility made numerous power sales into the California centralized markets. Due to financial problems experienced by numerous market participants, notably Pacific Gas & Electric (PG&E) and the California Power Exchange (PX) who filed for Chapter 11 bankruptcy in 2001, the Utility was not paid for many of these transactions. On June 4, 2008, the FERC approved a settlement agreement between the Utility and numerous California entities, including all of the Investor-Owned Utilities and the California Attorney General, under which the Utility was paid all of its unpaid receivables, plus interest, minus $1.27 million in refunds. The net payout to the Electric Utility was $3.7 million (including all unpaid receivables, including interest and its deposit with the Cal PX, minus $269,000 paid to the City of Banning for transactions made on its behalf by the Utility).
Under the settlement, the Utility may receive additional distributions of refunds from other sellers. The Utility also may

NOTE 9. LITIGATION (CONTINUED)

be responsible for paying its allocated portion (as determined by FERC) of payments due to other sellers for any Emission Offset, Fuel Cost Allowance, or Cost Offset associated with sales by such other sellers during the energy crisis. It is not possible at this time to estimate the net effect of any such future distributions to or payments by the Utility. The Utility is a defendant in various lawsuits arising in the normal course of business. Present lawsuits and other claims against the Utility are incidental to the ordinary course of operations of the Utility and are largely covered by the City's self-insurance program. In the opinion of management and the City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position or results of operation of the Utility.

NOTE 10. SPECIAL ITEM

On January 4, 2011, City Council approved the purchase of the 56-acre AB Brown Sports Complex property from the Water Utility to the Electric Utility for a fair market value of $11,600. The purchase was facilitated to balance the short and long-term investment and reserve assets of the Electric and Water Utility. The purchase will allow future appreciation of the property to accrue to the Electric Utility and will increase the financial liquidity of the Water Utility, both in efforts to maintain high credit ratings and to improve the overall financial position of both utilities.

The original and carrying value of the land in the Electric Utility is $17. The balance between the purchase price and carrying value of $11,583 is recorded as a special item.

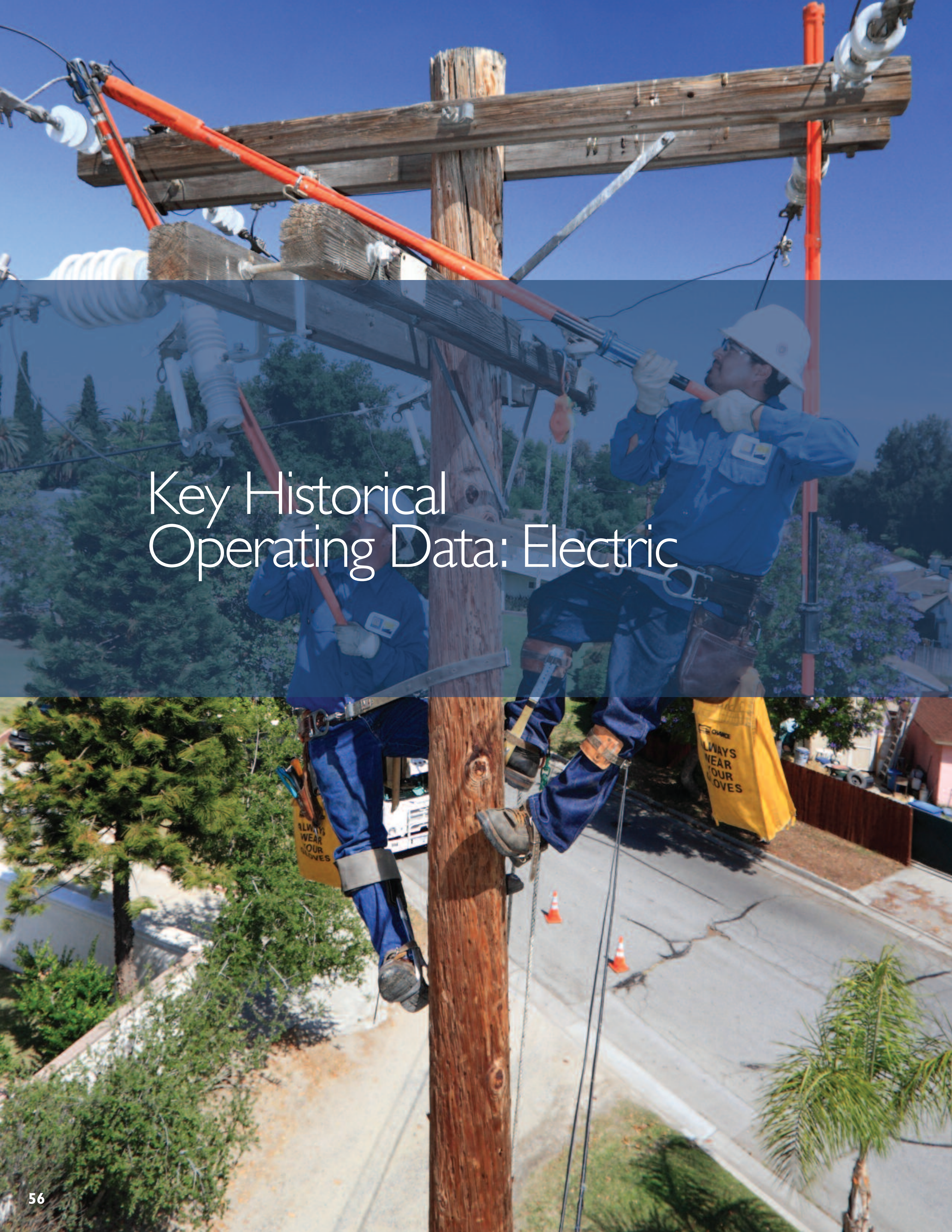
On March 1, 2011, City Council approved the purchase of certain property (Reid Park land and a 64 acre portion of the former Riverside Golf Course) from the Water Utility to the Electric Utility for a fair market value of $720 and $4,838 for the park and the golf course, respectively, for a combined total of $5,558 with a subsequent sale from the Electric Utility to the City's Redevelopment Agency. The land was originally purchased by the Water Utility in the 1930's to acquire water rights and expand certain well locations and is in excess to the current and long-term needs of the water system. The City intends that portions of the property (including the park) will remain public facilities and will be further developed for recreational purposes to benefit the community with another portion to be used for redevelopment purposes. The sale to the City's Redevelopment Agency is secured by a 20-year promissory note.

The original and carrying value of the property is $27. The balance between the purchase price and carrying value is $5,531 and is recorded as a special item.

NOTE 11. SUBSEQUENT EVENT

Hoover Uprating Project – Contract Renewals - Over the past two years, contractors from Arizona, Nevada, and California for the Hoover Uprating Project, have been meeting to negotiate terms for renewal of the contracts for electric service, which expire on September 30, 2017. The Contractors developed proposed legislation, that became known as the Hoover Power Allocation Act (the "Act"), which would extend the availability of Hoover power to the existing Contractors for an additional fifty years and create a pool for new entrants. The Act was first presented to both houses of Congress in late December 2009. Concurrently, Western proceeded with their administrative renewal process and drafted a similar proposal, including public comment meetings. The Act was passed by the House of Representatives on October 3, 2011 and by the Senate on October 18th, but because of some technical language changes to the enrollment of the bill, the House may need to pass a correcting resolution that authorizes these changes before the Act can become law. Western's process will be discontinued when the Act is passed and the Contractors plan to meet with Western to negotiate an agreement in conformity with the new law.

Key Historical Operating Data: Electric



KEY HISTORICAL OPERATING DATA

POWER SUPPLY (MWH)

	2010/11	2009/10	2008/09	2007/08	2006/07
Nuclear					
San Onofre	284,900	240,000	281,400	286,500	310,400
Palo Verde	102,000	96,300	97,700	85,200	90,000
Coal					
Intermountain Power	895,600	1,068,500	1,051,200	1,094,100	1,130,000
Deseret	0	187,400	406,000	427,600	400,000
Hoover (Hydro)	32,900	30,000	32,500	33,700	34,500
Gas					
Springs	3,100	1,400	3,300	2,300	1,600
RERC	34,500	11,500	48,700	46,800	62,000
Clearwater	9,700	0	0	0	0
Renewable Resources	385,700	354,900	233,000	247,800	245,000
Other purchases	464,200	276,500	349,200	594,100	462,000
Exchanges In	92,200	92,700	90,000	115,700	107,400
Exchanges Out	(176,100)	(156,200)	(160,600)	(202,600)	(191,900)
Total:	2,128,700	2,203,000	2,432,400	2,731,200	2,651,000
System peak (MW)	579.7	560.3	534.1	604.4	586.3

ELECTRIC USE

	2010/11	2009/10	2008/09	2007/08	2006/07
Number of meters as of year end					
Residential	95,676	95,258	95,214	94,691	94,232
Commercial	10,185	10,073	10,178	10,258	10,063
Industrial	908	916	904	978	837
Other	86	88	89	88	94
Total:	106,855	106,335	106,385	106,015	105,226
Millions of kilowatt-hours sales					
Residential	666	701	733	734	748
Commercial	400	406	433	441	456
Industrial	912	906	946	960	924
Other	31	32	33	34	39
Subtotal:	2,009	2,045	2,145	2,169	2,167
Wholesale	7	44	137	357	295
Total:	2,016	2,089	2,282	2,526	2,462

ELECTRIC FACTS

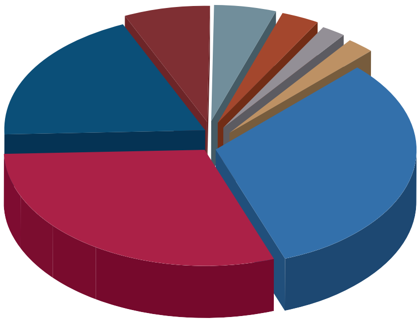
	2010/11	2009/10	2008/09	2007/08	2006/07
Average annual kWh per residential customer	7,006	7,397	7,739	7,779	7,959
Average price (cents/kWh) per residential customer	16.17	15.31	14.39	13.61	12.62
Debt service coverage ratio (DSC)[2]	2.21	2.75	2.58	2.62	3.09
Operating income as a percent of operating revenues	18.9%	23.5%	22.2%	16.4%	22.0%
Employees[1]	449	427	416	405	367

[1] Approved Positions

[2] For FY 10/11, interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.

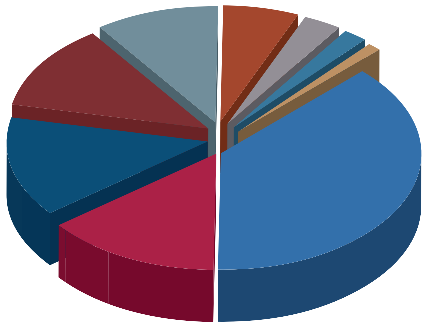
2010/2011 ELECTRIC REVENUE AND RESOURCES

Source of Revenue



- Residential Sales 32¢
- Industrial Sales 30¢
- Commercial Sales 19¢
- Transmission Revenue 7¢
- Other Revenue 5¢
- Investment Income 3¢
- Other Sales 2¢
- Public Benefit Programs 2¢
- Wholesale Sales (less than 1¢)

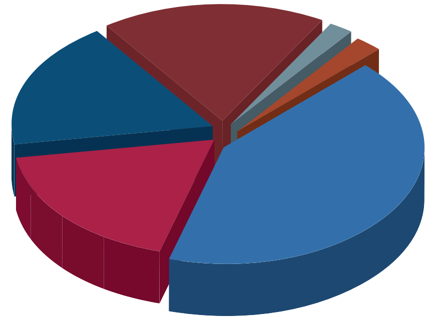
Distribution of Revenue



- Production 38¢
- Distribution 14¢
- Debt Service 14¢
- Transmission 12¢
- Transfers to the City's General Fund* 10¢
- Special Item 6¢
- Public Benefit Programs 3¢
- Additional Reserves 2¢
- Additions and Replacements to the System 1¢

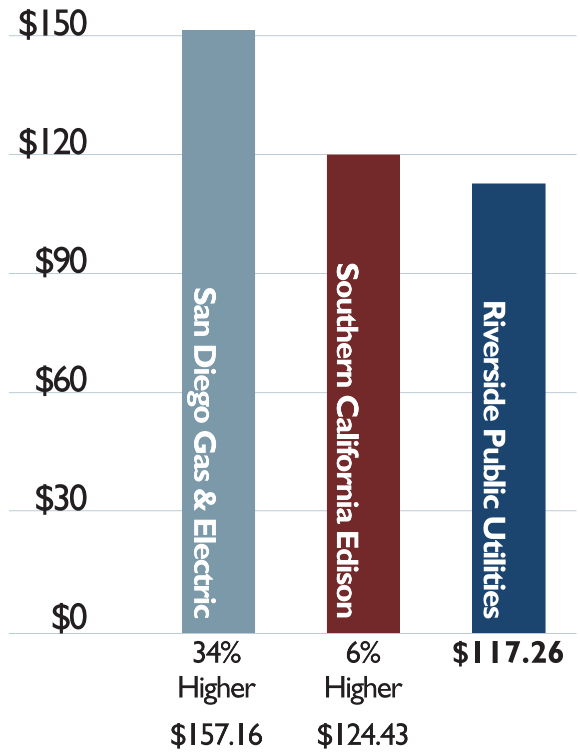
** Based on transfer of 11.5% of fiscal year 2009/2010 operating revenues (excludes wholesale sales and Public Benefit Programs revenues).*

Energy Resources

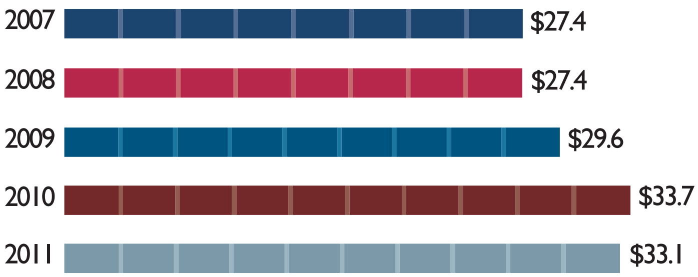


- Coal 42%
- Renewables 18%
- Nuclear 18%
- Other Purchases 18%
- Hydropower 2%
- Gas 2%

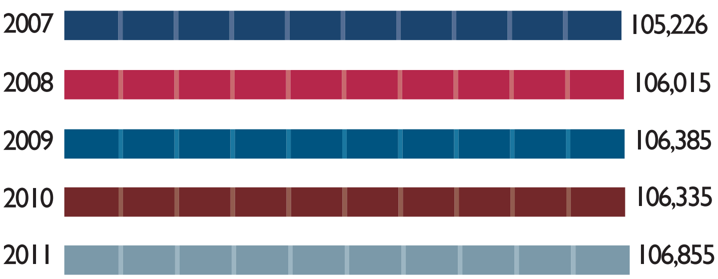
ELECTRIC RATE COMPARISON – 750 KWH PER MONTH (AS OF JUNE 30, 2011)



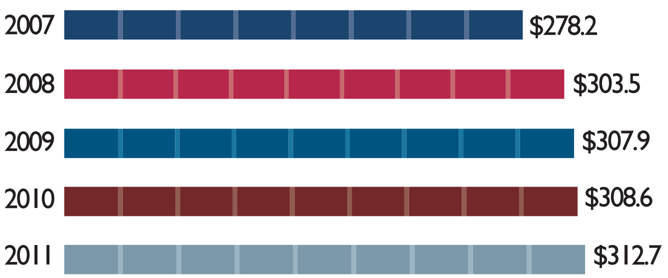
GENERAL FUND TRANSFER (IN MILLIONS)



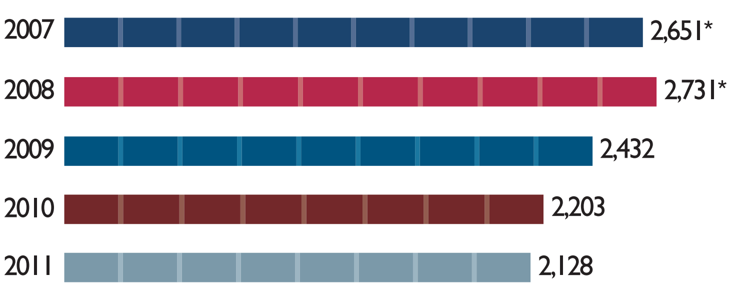
NUMBER OF METERS AT YEAR END



TOTAL OPERATING REVENUE (IN MILLIONS)

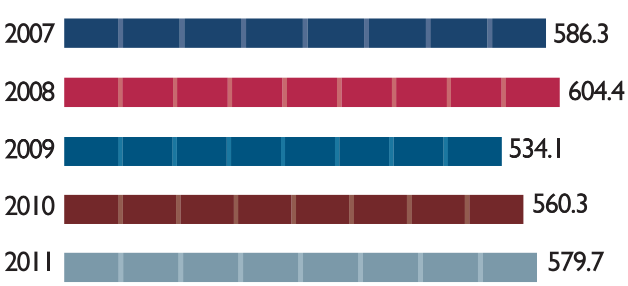


PRODUCTION (IN MILLION KILOWATT-HOURS)



** Energy shown before transmission losses net of exchanges*

PEAK DAY DEMAND (IN MEGAWATTS)



ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	306,779
Service Area Size (square miles)	81.5
System Data:	
Transmission lines (circuit miles)	91.1
Distribution lines (circuit miles)	1,308
Number of substations	14
2010-2011 Peak day (megawatts):	580
Highest Single hourly use:	
08/26/2010, 4 pm, 101 degrees	
Historical peak (megawatts):	604
08/31/2007, 4 pm, 106 degrees	

Bond Ratings

Fitch Ratings	AA-
Standard & Poor's	AA-
Debt Derivative Profile Score on Swap Portfolio	2

(1 representing the lowest risk and 4 representing the highest risk)